GUINNESS ATKINSON FUNDS

2018 Outlook for Energy

The Guinness Atkinson Global Energy Team, January 2018

2017 saw a year of rebalancing for oil, albeit slower than first hoped, as energy companies demonstrated improved resilience to the oil price environment. We'd like to share with you some big picture thoughts on 2017 events and our outlook for 2018 and beyond.

Highlights

2017 IN REVIEW

- 2017 was a year of modest tightening for the oil market. A combination of strong demand growth and OPEC production cuts more than offset a rise in production from the US shale oil system. OPEC's adherence to production cuts was as strong as at any time in the organization's history, culminating in a commitment announced at the end of November to bring OECD oil inventories back to normalized levels at some point in 2018.

- **The dominant themes for global oil markets last year were:**

  i) **Lower OPEC production, in an effort to rebalance the market**. 'Core' OPEC cut production by 1.2m b/day, offset partially by a recovery in production from Libya and Nigeria, as agreed in the OPEC plan. Venezuela struggled to keep up with its new quota, suffering from a lack of investment. OPEC announced in November that they would extend their production cuts to the end of 2018 to rebalance the market further.

  ii) **A return to non-OPEC supply growth, led by US shale.** Average production from the US onshore grew by 0.3m b/day, as the shale oil industry adapted to lower oil prices and the drilling rig count recovered. Leading edge data implies annualized growth from US onshore of 0.8m b/day. Non-OPEC supply outside the US rose slightly (+0.1m b/day), with growth from Canada and Brazil offset by declines in Mexico and China.

  iii) **Strong oil demand, expected to have grown by around 1.5m b/day.** This comprises **non-OECD oil demand** growth of 1.1m b/day (with China up 0.5m b/day) and **OECD oil demand** growth of 0.4m b/day, and represents a slightly better year than 2016 (+1.3m b/day). Synchronized global GDP growth across many regions, coupled with oil being priced at an 'affordable' level versus recent years, acted as the main catalysts to push demand higher.

- **For natural gas**, 2017 was a year of divergence between the US, Europe and Asia. In the US, the gas price was anchored at around $3/mcf by utility companies switching at the margin from gas to coal, whilst a tighter LNG market supported rising prices in Asia and Europe.

Energy equities underperformed the broad market in 2017, after a strong recovery year in 2016. Energy equity weakness over the first half of the year coincided with the oil price declining, as OPEC's production cut took time to filter through to tightening inventories. We saw the energy sector pick up in September, when falling inventories (led by strong demand growth) lifted oil and energy equities through to the end of the year. The MSCI World Energy Index ended 2017 with a total return of 5.95% versus the MSCI World at 23.07%. The performance of energy sub-sectors diverged considerably.

Improving free cash flows and a strong refining environment helped the integrateds to match the performance of the broader equity market (as a group up over 20%), whilst the E&P and service sectors were generally down 10-30%.

OUTLOOK FOR 2018

- **We expect OPEC to remain disciplined in its pursuit of normalized oil inventories, and will seek to manage the oil price in a $55-60/bl range.** OPEC are striving to find a 'happy medium' for the oil market where their own economics are better satisfied, the world economy is kept stable and US oil production grows in a controlled manner.
- **The US onshore shale system will grow strongly again this year, up by around 1m b/day if current oil prices persist.** Efficiency gains will occur but be offset by cost inflation across the oil services supply chain, with bottlenecks around high quality drilling and completion equipment. Improved capital discipline from shale producers is also expected.
- **Non-OPEC (ex US onshore) supply will hold up in 2018 but will come under increasing pressure** as upstream capex cuts from 2015-17 start to bite. A dearth of new project sanctions and increasing decline rates on existing fields means that non-OPEC (ex US onshore) oil production will decline into the end of the decade, even if oil prices increase from here.
- **Global oil demand is likely to remain robust** as GDP growth, vehicle miles traveled and consumer demand habits mean that gasoline demand continues to grow. The non-OECD will deliver most of the growth in 2018, with China and India leading the way. Electric vehicles will come, but pose no threat to current oil demand growth.
- **OECD oil inventories will likely normalize by the end of the year** but the path will be bumpy. Historically, a decline in inventories has been supportive for oil prices, as we saw in the second half of 2017. Looking further ahead, we believe that continued oil demand growth, and a decline in non-OPEC supply outside the US, will raise the call on the US shale system and OPEC, and allow OPEC to manage the market to a higher price.
- **Global gas demand will grow handsomely again in 2018** led by strong Asian GDP growth and a shift in the region from coal to gas consumption by power utilities.
- **Energy equity valuations remain at depressed levels.** On a relative price-to-book (P/B) basis (versus the S&P500), the valuation of energy equities has fallen back to a 50 year low, at 0.5x, the same level that it was at in February 2016 when Brent oil was $29/bl. Low P/B ratio for the sector have been driven by poor levels of return on capital but, with better capital discipline, returns are now improving and should drive higher valuations.
- **Free cash flow will become a growing priority in 2018.** Energy companies will improve free cash flow returns in 2018, via cost control, capital restraint and a reduction in unproductive capital, even in a static oil price environment.

- Looking ahead to 2019/2020, with a $60 oil price, **we expect oil & gas companies to be able to grow shareholder distributions meaningfully for the first time in a decade**. Super majors could raise distributions by 40%, whilst mid and large cap producers could raise them by 80%.

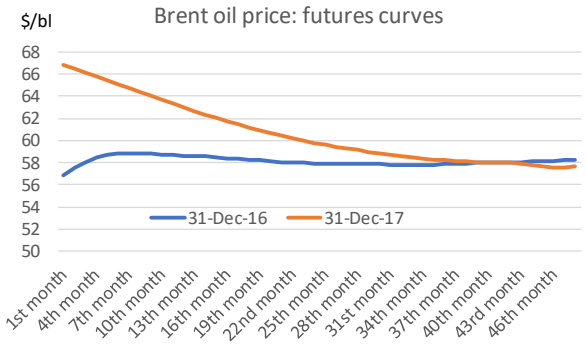
Energy equities offer attractive upside if our scenario plays out. If you believe, as we do, in a supportive oil price environment or improving return on capital (or both), our sensitivity work shows upside across the energy complex of around 35-45%.

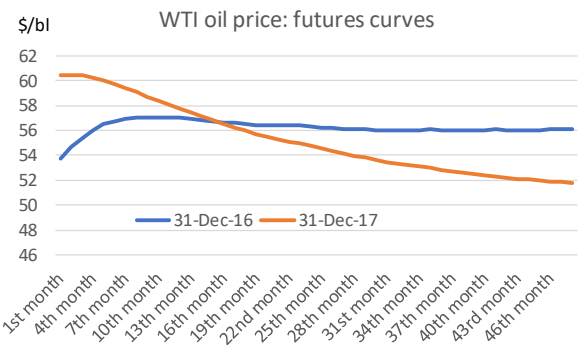
Review of 2017

2017 was a year of tightening for the oil market. A combination of strong demand growth and OPEC production cuts more than offset a rise in production from the US shale oil system. OPEC's adherence to production cuts was as strong as at any time in the organization's history, culminating in a commitment announced at the end of November to bring OECD oil inventories back to normalized levels during 2018.

Volatility in the **oil price** was less pronounced in 2017 than the previous year, with Brent spot trading in a range from $45-67/bl. Brent oil started the year in the mid $50s/bl, but dipped over the summer as it took time for OPEC's production cuts to feed through into the export market, causing the market to become skeptical of their approach. The price then recovered over the final four months of the year as inventories visibly tightened. The average Brent spot oil price in 2017 was $55/bl, $12/bl higher than 2016. WTI (West Texas Intermediate) spot averaged $4/bl lower at $51/bl, as a combination of hurricane-induced refinery disruption and resurgent US production created a divergence to Brent.

There was also a marked change in the shape of the oil futures curve, with both Brent and WTI shifting from contango to backwardation, indicating a tighter nearer term market. However, allied to this, we saw long dated oil prices move lower. The four year forward price for Brent dropped by 1%, whilst four year forward WTI dropped by 8%, reflecting a market view that a price in the low to mid $50s/bl will be sufficient in the coming few years.





Source: Bloomberg

The major components of oil supply/demand for 2017 were as follows:

- **OPEC oil supply (including NGLs)** is likely to have declined by around 0.3m b/day (totaling 39.1m b/day, versus 39.4m b/day in 2016). Commencing on January 1, 2017, OPEC announced 1.2m b/day of production cuts, marking a reversal of the shift to a market share strategy seen in 2014. Compliance to

the cuts was generally strong, led by Saudi Arabia. Offsetting the cuts, however, we saw recovery in production from Libya and Nigeria, both of which had been left to grow after production had been disrupted. In November, OPEC announced that they would extend their production cuts to the end of 2018 in an effort to rebalance the market further;

- **Non-OPEC oil supply** is likely to have grown by around 0.6m b/day in 2017 (58.0m b/day, versus 57.4m b/day in 2016). Production from the US onshore grew by 0.3m b/day, as the shale oil industry adapted to lower oil prices and the drilling rig count recovered to an average of 702 (vs 408 in 2016). Increases in production were also reported in Canada (+0.3m b/day) and Brazil (+0.2m b/day), offset by declines in Mexico (-0.2m b/day) and China (-0.1m b/day). A group of non-OPEC countries, headed by Russia, contributed around 0.3m b/day of production cuts in 2017 alongside OPEC's efforts, though Russia's average production for the year was still up slightly;
- **Global oil demand** is estimated to have grown by around 1.5 m b/day in 2017, according to the IEA. This comprises **non-OECD oil demand** growth of 1.1m b/day (with China up 0.5m b/day) and **OECD oil demand** growth of 0.4m b/day. If confirmed, the figures represent a slightly better year for oil demand than 2016 (+1.3m b/day). Synchronized GDP growth across many regions, coupled with oil continuing to be priced at an 'affordable' level versus recent years, acted as the main catalysts to push demand higher. In China, gasoline demand from passenger vehicles and kerosene demand from air travel were the main areas of growth, whilst industrial demand for oil steadied. The US saw passenger vehicle miles traveled grow by about 2%, boosted by another year of low gasoline prices;
- **OECD oil inventories** at the end of October 2017 were estimated to be at 2,940 million barrels, down from 3,047 million barrels at the end of October 2016, but still 7% above the 10-year average. The decline in inventories over the last 12 months implies that the market has been, on average, around 0.3m b/day undersupplied, versus an oversupply of 0.1m b/day for the prior 12 months. There have been other factors at play in 2017, notably the release of oil in offshore storage into the onshore OECD inventory system, which have dampened market tightness. Stripping these effects out, we assess the fundamental level of global undersupply in 2017 as being closer to 0.5m b/day.

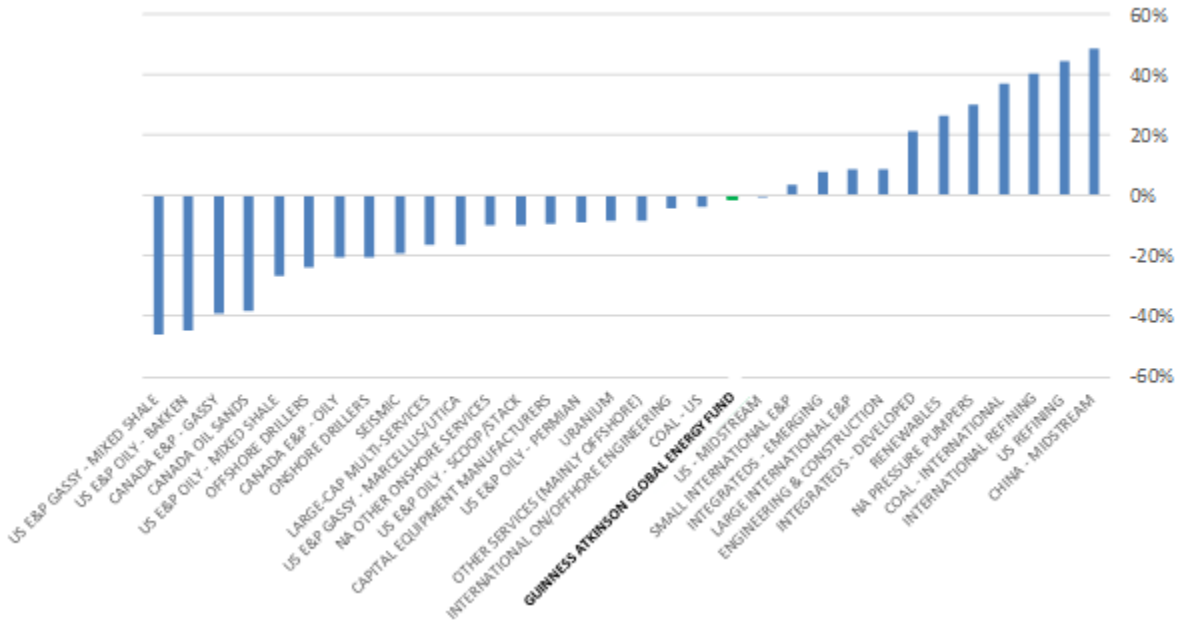
For **natural gas**, 2017 was a year of divergence between the US, Europe and Asia. In the US, the gas price was anchored around $3/mcf (averaging $3.02/mcf). This represented a recovery from 2016 (when price averaged $2.55/mcf), but the price was held back by gas to coal switching, as US utility companies took advantage of relatively lower coal prices, and a return to growth for onshore gas production in the second half of the year.

Outside the US, gas prices started the year weakly, as another warm winter translated into low demand for heating and high inventories of gas in several regions across Europe and Asia. However, gas prices across both regions then rallied strongly after the northern hemisphere summer, as strong LNG demand in Asia tightened the seaborne LNG market for gas across the globe and tightened the gas market generally. European natural gas averaged $5.7/mcf (vs $4.7/mcf in 2016) and Asian natural gas (as measured by the 'JLNG' contract) averaged $6.9/mcf (vs $6.1/mcf in 2016).

After a strong year for **energy equities** in 2016, we saw a 'V' shaped performance in 2017, with the sector finishing behind the broad market. Weakness over the first half of the year coincided with the oil price declining from the mid $50s to mid $40s per barrel, as OPEC's production cut took time to filter through to tightening inventories. The sector then range traded until September, when falling oil inventories lifted oil and energy equities through to the end of the year. A particularly strong year for many other equity sectors, however, saw energy equities ultimately falling well behind the broad stock market. The MSCI World Energy Index ended 2017 with a total return of 5.95% versus the MSCI World at 23.07%.

As usual, the performance of the MSCI World Energy Index was only part of the story, with 2017 being a year of extreme divergence between the core energy subsectors. In particular, we saw the greatest divergence since 2011 between integrated, exploration and production, and energy service companies. Buoyed by improving free cash flows and a strong refining environment, the integrateds matched the performance of the broader market (as a group up over 20%), whilst the E&P and service sectors were weaker, held back by falling longer dated oil prices, and generally down 10-30%.

Global energy equity subsectors: median total return in 2017 (%)



Source: Bloomberg; Guinness Atkinson Asset Management

A quick tour of some of the main energy sub-sectors paints a picture for the energy equity sector's performance in 2017:

- **Integrated oil and gas companies.** A year of strong performance, particularly for the European majors which started the year priced less expensively than their US counterparts. 2017 was the year when the large cap integrateds demonstrated that they could cover their dividends at around $55/bbl, thanks to lower but sustainable capital spending, and rationalizing of operating costs. We saw the removal of scrip dividends for some of the majors (e.g. Shell), and the introduction of share buyback programs (e.g. BP) for the first time in many years. Cash flows for the integrated group were also assisted by strong refining margins across the globe, boosting downstream profits.

- **Oil refining**. One of the better performing sub-sectors, particularly in the US and Europe, with refining equities up over the year. Stronger than expected GDP growth supported oil demand growth, which in turn kept refining margins at elevated levels. The Atlantic basin refining system received a boost in August/September with the heaviest hurricane season for many years causing a shortage in US Gulf Coast refining capacity and a short-term spike in refining margins. As payers of cash taxes, US refiners were also one of the main beneficiaries in the energy sector of Republican tax reforms, with corporation tax due to fall to 21%.

- **Renewables**. A recovery year after a poor 2016. Politically, it came as relief that President Trump initially steered away from promised attacks on renewable energy support in the US, appearing

to direct his attention elsewhere. In the solar market, we saw a year of record installed capacity globally, driven by an unexpected increase from China (up from 30GW in 2016 to over 45GW in 2017). Increased solar demand meant some stabilization in module prices, after several years of price decline, supporting earnings.

- **Exploration and production**. Generally a poor year. Whilst spot oil prices strengthened during the year, longer dated crude prices declined, which pushed E&P equities lower. The better performers tended to internationally focused producers, enjoying exposure to Brent (where spot and long dated prices held up better than US focused WTI prices). In the US, Permian producers, with adequate levels of drilling inventory to expand into, tended to be best insulated from the declines. At the weaker end of the spectrum, US gas producers were hit particularly hard, as were US companies with high cost/ short life shale positions and who saw the need to purchase additional inventory, particularly in the Permian basin, at high prices.

- **Energy services**. Generally weak. An uplift in activity was strongest in those businesses oriented towards the onshore US shale oil market (e.g. pressure pumping), though expectations leading into the year were high, and the failure of operating margins to improve as much as some had hoped led to weaker share prices. Offshore services (offshore drillers, seismic, offshore-oriented capital equipment manufacturers) continued to struggle, as capital spending continued to be diverted to shorter-cycle onshore activity.

The **Guinness Atkinson Global Energy Fund** in 2017 produced a total return of -1.06%. This compares to the total return of the MSCI World Energy Index of 5.95%. The underperformance of the Fund versus the Index can be explained in broad terms by the Fund's higher weighting to E&P companies and corresponding lower weighting to integrateds. It was a strong year for the largest five oil and gas majors (Exxon, Chevron, Total, Shell and BP, which comprise around 45% of the Index), up on average by 14% over the year, pulling the index performance higher. Within the Fund, the best performing investments were generally large and mid-cap European integrateds (Statoil, Royal Dutch Shell and BP), and refiners (OMV and Valero), all of which enjoyed the strong demand environment globally, plus solar manufacturers/ developers (JA Solar, Sunpower). The weakest investments were US diversified E&Ps (QEP Resources, Carrizo, Apache and Noble), suffering the decline in longer dated oil prices, and large cap services (Schlumberger and Halliburton), as the operating environment improved but not as rapidly as share prices in the sector had been anticipating.

Performance as of 12/31/17

	2017	1 Year	3 Years	5 Years*	10 Years*	Since Inception (June 30, 2004)*
Global Energy Fund	-1.06%	-1.06%	-2.81%	-1.67%	-2.10%	6.82%
MSCI World Energy Index	5.93%	5.93%	1.74%	2.21%	0.26%	6.75%

***Periods over 1 year are annualized returns**

*Performance data quoted represents past performance; past performance does not guarantee future results. The investment return and principal value of an investment will fluctuate so that an investor's shares, when redeemed, may be worth more or less than their original cost. Current performance of the fund may be lower or higher than the performance quoted. Performance data current to the most recent month end may be obtained by calling 800-915-6566 and/or visiting **www.gafunds.com***

Prospectus expense ratio: 1.53% gross, 1.45% net

The outlook for 2018

Oil supply

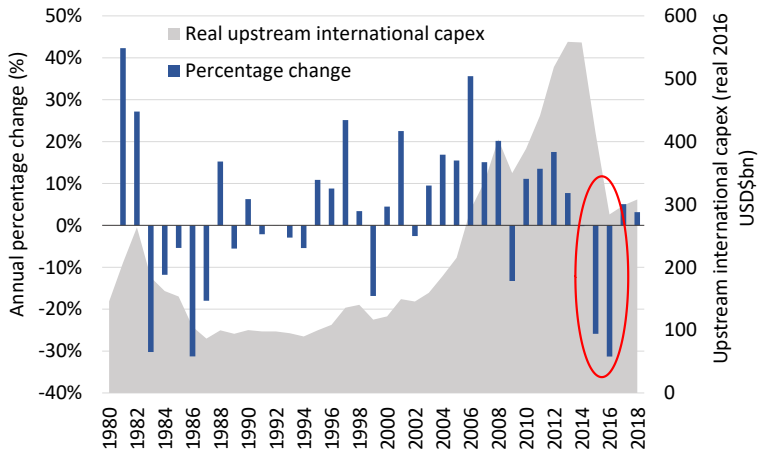
To address the outlook for world oil supply in 2018, we have divided the producing world into: non-OPEC (ex US onshore), US onshore shale and OPEC. We expect small growth in non-OPEC (ex US onshore) supply in 2018, US onshore shale oil to grow well and continued OPEC supply discipline for as long as it is needed to keep a balanced market. As we look to the end of the decade, however, we see non-OPEC (ex US onshore) supply declining, creating a greater call on the US and OPEC to satisfy demand.

Non-OPEC (ex US onshore) oil supply

Despite representing over half of world oil supply (50.9m b/day in 2017), non-OPEC (ex US onshore) production receives relatively little attention. The outlook for this group of producing countries will be shaped by patterns in capital expenditure over the past five years or so, as there tends to be a multi-year lag between investment decision and production start-up. In particular, we see the significant cut in capital expenditures in 2015 and 2016 as starting to have relevance to supply in 2019 and 2020.

Upstream capital expenditure growth is expected to have risen around 5% in 2017 (having been down 31% in 2016 and down 26% in 2015) but at around US$300bn, is still down 45% on the peak level of US$545bn in 2013/14. The scale of the shortfall in investment, driven by lower oil prices, is reflected in comments made by the CEO of Schlumberger (Paal Kibsgaard) in March 2017:

Non-OPEC (ex US onshore) upstream capital expenditure



"At no other time in the past 50 years has our industry experienced cuts of this magnitude and this duration. While the market continues to focus on the headline numbers which suggest that production is holding-up well even in the third successive year of underinvestment, a closer look at the underlying data reveals that the current situation is not sustainable."

Source: JP Morgan; Guinness Atkinson

Forecasts are inherently limited and cannot be relied upon.

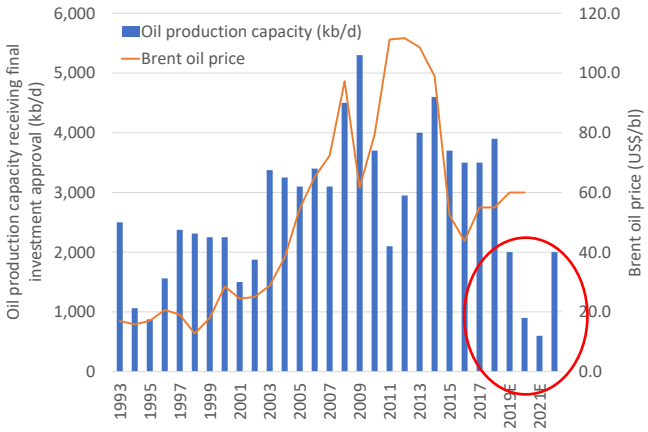
Whilst deflationary pressures have reduced the unit cost of developing new oil and gas fields (for example deep water drilling rigs that were contracted out at peak rates of $600k/day were being re-contracted at $150k/day during 2017), the reality is that activity levels are still sharply lower and are causing two broad effects:

- **Increased decline rates.** As a result of lower spending on maintenance activity and infill drilling we have seen production from various mature areas of the world declining faster than previous rates. Mexican production is particularly under pressure, whilst Norwegian oil production also now looks to be declining. According to Bernstein Research, analysis of previous oil price downturns indicates that decline rates increase by 2-3% p.a. because of lower reinvestment;

- **A lower number of new projects being developed.** Owing to lower cash flows and poorer new project economics, oil production associated with newly developed fields is expected to fall into the end of the decade, reaching levels not seen in the last 30 years or so. Typically, there is a three or four-year time lag between investment and production and we note that the heavy investment period of 2011-2014 has allowed new non-OPEC (ex US onshore) oil developments to be remarkably robust through 2016, 2017 and 2018. Even if oil prices were stronger in 2018 (and investment in new projects picked up) it would be too late to boost production before 2021. A supply decline appears to be coming as a result of lower oil prices.

Putting these factors together, we expect non-OPEC (ex US onshore) oil production to start to fall in 2019 and to continue falling for a further two or three years. Any shortfall will need to be offset either via greater OPEC production, greater US onshore production or lower oil demand growth. While this may not be impacting world oil markets today, there is increasing risk of a non-OPEC (ex US onshore) supply shortage over the next few years.

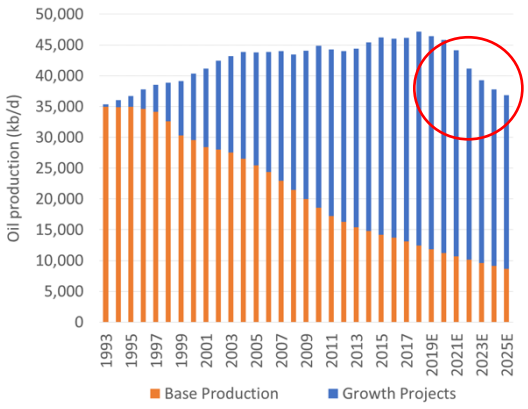
Non-OPEC (ex US onshore) oil production capacity receiving final investment decision



Source: Bloomberg; Guinness Atkinson

Forecasts are inherently limited and cannot be relied upon.

Non-OPEC (ex US onshore) oil production profile split into base and growth project



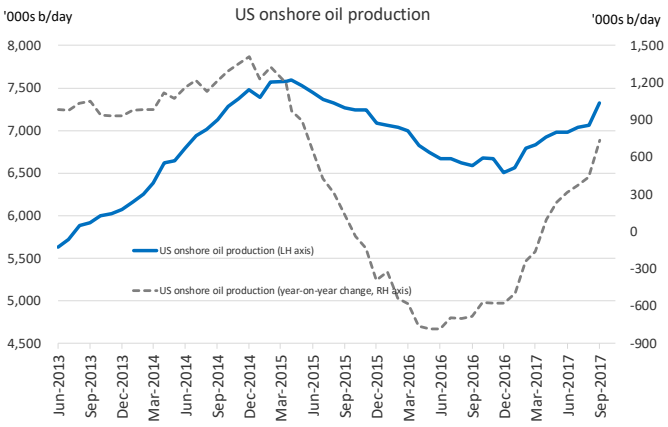
Source: Bloomberg; Guinness Atkinson

Forecasts are inherently limited and cannot be relied upon.

US onshore (shale) oil supply

The dynamics of the US onshore oil industry, developing unconventional oil, are quite different to those of the rest of non-OPEC and it is this new short cycle supply source that will continue to keep non-OPEC production, as a whole, at robust levels through 2018.

Non-OPEC (ex US onshore) oil production capacity



Source: EIA (Energy Information Administration); Guinness Atkinson Funds

US oil-directed drilling activity recovered over 2017 from 525 rigs to 747 rigs, leading US onshore production to rebound from 6.8m b/day on average in 2016 to an estimated 7.1m b/day in 2017. The most recent monthly data for US onshore supply now indicates leading edge growth of 0.8m b/day between September 2016 and September 2017. Clearly the US system has adapted to the lower oil price environment and is growing well again after declining in 2016.

US oil and gas producers have proved themselves to be nimble and the low-price environment has forced them to become more selective in where they drill wells and more efficient in their approach to drilling and fracturing. There were a number of concerns in the middle of 2017 regarding the productivity of the US shale system and the hurricanes in August/September 2017 had a one-off detrimental impact on production. Nonetheless, the US recovered and we now believe that, if Brent oil prices are sustained in a $50-60/bl range (as we believe OPEC will target near term), the US onshore system will deliver supply growth of between 0.6 and 1.2m b/day. Structural improvements in terms of the length of laterals being drilled, the speed of drilling and the intensity and location of fracturing jobs all mean that the US is delivering more production and reserves per dollar invested than it was in the peak of activity in 2013/14.

The pick-up in activity has already started to cause a number of 'pinch points' in the supply chain and we are seeing quite material cost inflation in various parts of the system. Issues around labor shortages, infrastructure shortages (particularly in the Permian basin) and the availability of high quality drilling and completion equipment will all become more prevalent in 2018. So, as activity picks up, we fully expect to see increasing cost inflation across the broader oil services supply chain and the moderation or reversal of efficiency gains as lower quality operators and lower quality drilling opportunities start to become a larger part of the activity mix.

Brent oil price	Production change
$30-40/bl	Declining 0.3-0.5m b/day
$40-50/bl	Broadly flat
$50-60/bl	Increasing around 0.6-1.2m b/day
$60-70/bl	Increasing around 1.2-1.6m b/day

We then ask ourselves: "What oil prices are required to incentivize various levels of production response?" It is a complex question to answer as efficiency gains, cost inflation, resource quality and asset focus affect the overall responsiveness of the US onshore oil production system. Moreover, in the last few months, some E&P companies have started to pursue strategies of 'capital discipline' (in order to boost corporate returns on capital) and the forward curve has moved into backwardation (making it less attractive for producers to hedge forward oil price exposure). Both these factors could reduce the level of production response from the US onshore system at a given oil price.

Weighing the various factors up, our US oil supply model implies that US onshore oil production is likely to remain flat at an underlying oil price of $40-50/bl and that oil prices of $50-60/bl and $60-70/bl will be

required to incentivize production growth of 0.6-1.2m b/day and 1.2-1.6m b/day respectively, assuming no material 'capital discipline' impacts. Look further forward, as more shale wells are drilled the 'underlying' decline rate of US oil production will get gradually higher meaning that incrementally more wells will have to be drilled every year to deliver production growth.

In the near term, extra US onshore growth is likely to dampen oil price strength, but into the end of the decade, the 'call on the US onshore' could become quite substantial as other non-OPEC production starts to decline.

Guinness Atkinson estimates

OPEC oil supply

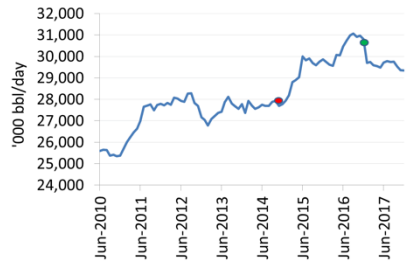
2017 was a year of supply discipline from OPEC as it worked to rebalance the oil market through a new production quota system. Starting 2018, there appears to be continued cohesion between OPEC and its non-OPEC peers, united in the desire to bring OECD oil inventories back to normal levels. We continue to think that Saudi are managing the oil price in a rational fashion: trying to support the price as high as possible, whilst avoiding pushing it too high and over-stimulating US shale oil production.

At the most recent OPEC meeting at the end of November 2017, OPEC's main announcement was an extension of the existing 1.2m b/day production cuts to the end of 2018. There was a continued understanding that non-OPEC will also keep 0.6m b/day of production off the market, headed by 0.3m b/day from Russia. November production data implied 113% compliance to the cuts for OPEC (excluding Nigeria and Libya which were exempt from the quota system announced in January 2017).

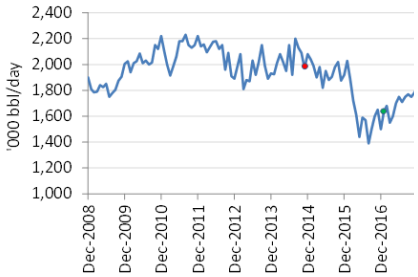
One new aspect to production controls announced in November was that Libya and Nigeria saw their production capped at current supply levels (1.0m b/day and 1.8m b/day). This means that 2018 will not see a repeat of 2017, when production cuts from the rest of OPEC were partially offset by Nigerian and Libyan supply recoveries.

Looking ahead to a time when inventories have normalized, OPEC and Russia have so far not articulated an exit-strategy from the production cuts. Saudi have reiterated, however, that when the time comes to end the production curbs, the process will be gradual and deliberate and will not bring about a sudden steep increase in production.

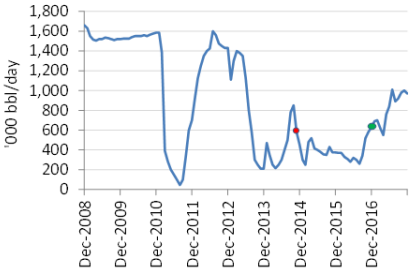
OPEC-12 ex Libya and Nigeria oil production



Nigeria oil production



Libya oil production



Source: Bloomberg; Guinness Atkinson
Note: Red dot = November 2014 market share strategy, Green dot= January 2017 new quota implementation

We believe that there are strong economic reasons driving OPEC's strategy. Many OPEC economies, despite cost cutting and restructuring, still require a high oil price to balance their fiscal budgets. Saudi, as an example, continued to reduce its foreign reserves in 2017 and its 2018 budget (estimated to be based

on an oil price of between $50 and $55/bl) implies an outspend of just over US$50bn. There is a desire for the planned IPO of Saudi Aramco in mid 2018 to be a success both in terms of supplementing near term financing but also in terms of reducing the reliance of the Saudi economy on crude oil. We believe Saudi are seeking a reasonable oil price in 2018 to facilitate a good valuation for Aramco.

Venezuela oil production

Source: Bloomberg; Guinness Atkinson Funds

The strains of a low oil price environment are also showing up in the production profiles of some of the poorer OPEC countries. Venezuelan oil production was the biggest casualty in 2017, and we expect a further decline in 2018, while Angola is likely to suffer depressed production for a number of years as a result of stagnation in new developments.

While market focus is on compliance with production quotas, we must not forget the risk of escalated political instability within OPEC. 2017 witnessed further Shia-Sunni tensions in the region and we remind ourselves that almost all of Saudi's oil output passes through the Shia heartland of Saudi Arabia. Proxy Sunni-Shia wars are either brewing or being fought in Syria, the Yemen and the Lebanon and the risk of supply disruption at some point cannot be excluded. With OPEC spare capacity likely to be in a 2-3m b/day level, world oil markets would likely react violently to any OPEC supply disruption.

Oil demand

The IEA are forecasting growth in oil demand in 2017 of around 1.5m b/day, higher than 2016 and well above the 10-year average. 2018 demand growth is expected to be 1.3m b/day. The IEA tie their 2018 estimate in with the current IMF forecast for global GDP growth of 3.7%. We expect that if global GDP growth is as strong as 3.7% in 2018, actual oil demand growth will be closer to 1.5m b/day. In common with 2017, the lion's share of oil demand growth in 2018 comes from Asia, with the rest of non-OECD demand supported by growth from the Middle East. OECD demand in 2018 is forecast to be essentially flat, with slight growth in North America offset by a small decline in the Pacific region.

What were the key demand developments last year, and how do they bode for 2018 and beyond?

Demand growth in China accelerated in 2017. Gasoline demand for passenger vehicles and kerosene demand for air transportation saw another strong year: we estimate that demand for both grew by more than 10%. Underpinning gasoline demand growth, 2017 saw record vehicle sales in China, estimated at 24m units vs 23m units in 2016. However, the key swing factor for demand was a reversal in declining diesel consumption (linked more to China's industrial sector), which is estimated to have grown by 1.8% this year after falling by 3.7% in 2015 and 1.2% in 2016. We expect similar demand patterns from China in 2018, with shallow 'industrial' demand growth supporting faster 'consumption' demand growth.

World oil demand 2004-18

Source: IEA (International Energy Agency); Guinness Atkinson

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
OECD demand														IEA	IEA
North America	25.7	25.8	24.5	25.8	24.5	23.7	24.1	24.0	23.6	24.2	24.2	24.6	24.7	24.9	25.0
Europe	15.6	15.7	15.7	15.6	15.5	14.7	14.7	14.3	13.8	13.6	13.5	13.8	14.0	14.3	14.3
Pacific	8.8	8.9	8.7	8.7	8.3	8.0	8.2	8.2	8.5	8.3	8.1	8.1	8.1	8.1	8.0
Total OECD	**50.1**	**50.4**	**48.9**	**50.1**	**48.3**	**46.4**	**47.0**	**46.5**	**45.9**	**46.1**	**45.8**	**46.4**	**46.9**	**47.3**	**47.3**
Change in OECD demand		*0.3*	*-1.5*	*1.2*	*-1.8*	*-1.9*	*0.6*	*-0.5*	*-0.6*	*0.2*	*-0.3*	*0.6*	*0.5*	*0.4*	*0.0*
NON-OECD demand															
FSU	3.8	3.9	4.0	4.0	4.2	4.0	4.1	4.4	4.6	4.5	4.6	4.5	4.8	4.8	4.9
Europe	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.8
China	6.4	6.7	7.2	7.6	7.7	7.9	8.9	9.3	9.9	10.4	10.8	11.6	11.9	12.4	12.8
India	2.6	2.6	2.7	2.9	3.1	3.2	3.3	3.5	3.7	3.7	3.8	4.2	4.6	4.7	5.0
Other Asia	6.4	6.4	6.6	6.9	6.8	7.1	7.5	7.6	7.6	7.9	8.0	8.2	8.4	8.7	8.9
Latin America	4.9	5.0	5.2	5.3	5.6	5.7	6.1	6.2	6.5	6.6	6.8	6.7	6.6	6.6	6.7
Middle East	5.5	5.9	6.1	6.4	6.7	7.1	7.3	7.5	7.9	8.0	8.4	8.4	8.3	8.3	8.5
Africa	2.8	2.9	2.9	3.3	3.3	3.4	3.5	3.5	3.8	3.8	3.9	4.1	4.1	4.2	4.3
Total Non-OECD	**33.1**	**34.1**	**35.4**	**37.1**	**38.1**	**39.1**	**41.4**	**42.7**	**44.8**	**45.6**	**47.3**	**48.5**	**49.4**	**50.6**	**51.9**
Change in non-OECD demand		*1.0*	*1.3*	*1.7*	*1.0*	*1.0*	*2.3*	*1.3*	*2.1*	*0.8*	*1.7*	*1.2*	*0.9*	*1.2*	*1.3*
Total Demand	**82.5**	**83.8**	**85.1**	**87.2**	**86.4**	**85.5**	**88.4**	**89.2**	**90.7**	**91.7**	**93.1**	**95.0**	**96.3**	**97.8**	**99.1**
Change in demand		*1.3*	*1.3*	*2.1*	*-0.8*	*-0.9*	*2.9*	*0.8*	*1.5*	*1.0*	*1.4*	*1.9*	*1.3*	*1.5*	*1.3*

Forecasts are inherently limited and cannot be relied upon. Holdings are subject to change.

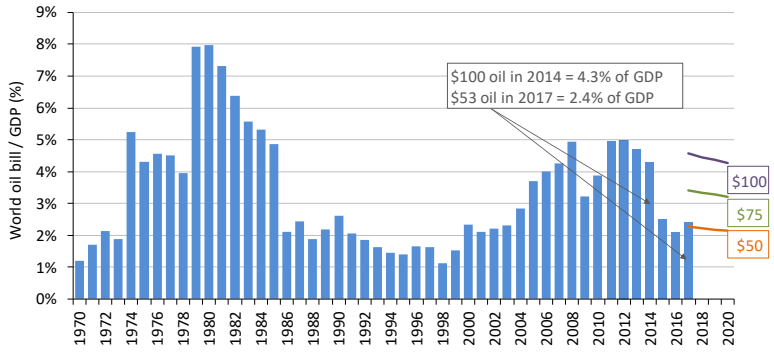
Indian oil demand had a slower year in 2017, as demonetization held back the economy. In 2018, we expect demand growth of 0.3m b/day (vs 0.1m b/day in 2017), as all segments of product demand except kerosene (which will decline as the government encourages households to switch to LPG for cooking) to grow again. India consumes less than 40% of the amount of oil used by China (despite having a similar population), and we expect the gap to close over the next few years as Indian GDP growth drives Indian car sales and an expanding manufacturing industry.

In the OECD in 2017, European oil demand was especially strong, up 0.3m b/day, thanks to a better-than-expected recovery in the energy-intensive industrial sector. The IEA forecasts much lower growth for Europe in 2018, but better growth from the US as passenger vehicle miles grind higher.

Patterns of demand growth in the OECD and non-OECD that have developed since the fall in the oil price in 2014 show a contrasting trend between the two regions.

- In the OECD, demand has been more price elastic, with lower oil prices in 2015/2016/2017 resulting in above trend demand growth, relative to the level of GDP growth reported.
- In the non-OECD, however, oil demand has proved to be more price inelastic, with the level of growth largely unaffected by the drop in price.

The world oil 'bill' as a percentage of GDP



Source: Bloomberg, Guinness Atkinson Funds

It is worth noting that this effect has been amplified by the removal of refined product subsidies in some emerging market countries (e.g. India; Indonesia), which has limited the change in prices for the end-consumer relative to swings in the crude price. How does the current burden of oil spending compare to history?

Forecasts are inherently limited and cannot be relied upon.

With the oil price (a weighted blend of Brent and WTI) averaging around $53/bl last year, it implies that the world spent 2.4% of GDP on oil in 2017. This is considerably lower than the average world 'oil bill' from 1970 to 2016 of 3.4% and keeps the spend on oil close to the 'cheap' 1986-2003 range (averaging 1.9% GDP) which stimulated a significant wave of new demand. If oil returned to the 45-year average level of 3% of GDP, this implies a recovery in price to $66/bl, inflating to around $72/bl by 2020 as inflation and improved efficiency in the use of oil take effect.

Impact of electric vehicles on oil demand

Developments in the 'new energy' vehicle fleet were dominated by headlines from car manufacturers and governments confirming their commitment to electric vehicles in the long term. Volvo announced a switch to manufacturing electric and electric hybrid vehicles only in 2019, and the UK and French governments recently announced bans on the sales of pure combustion engine cars by 2040. Given it looks likely that an increasing proportion of passenger vehicles will be fully or partly electric, these headlines raise questions around the future trajectory for oil demand growth.

As a general comment, we believe electric vehicles (EVs) will eventually penetrate the passenger vehicle market, but see nothing that makes a significant dent in the consumption of gasoline and diesel in the next few years, let alone the wider market of global oil consumption.

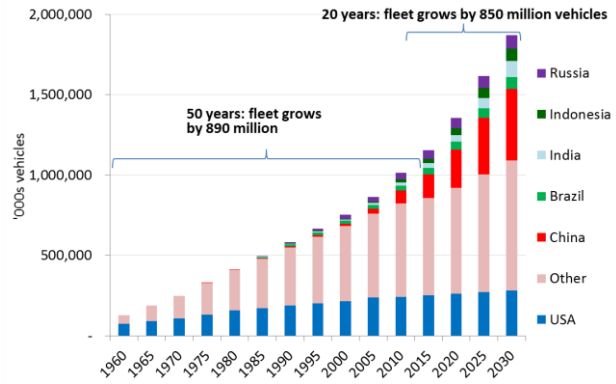
We are now in an era where the absolute growth rate for light vehicles is expanding rapidly. Global car sales in 2017 grew by 1.5% to 78.6m units, almost 50% higher than the annual average sales rate in the 2000s (c.52m units), and nearly double the annual average sales rate of the 1990s (c.39m units).

We see a likelihood that the global vehicle fleet grows by as much over the 20 year period from 2010 to 2030 as it did in the previous 50 years, bringing the world's light vehicle population to around 1.8bn, from 1.3bn today. This would represent an average growth rate of 2.9% per annum, just below the 3% growth rate recorded between 1990 and 2015.

What will the pace of electric vehicle adoption then be? The history of forecasting the penetration of new technologies is one strewn with bias and misjudgment. We are still at an early stage in terms of the path of EV sales and, acknowledging its limitations, find the best approach to consider a scenario which is towards the more aggressive end of current forecasts in the market.

Modelling the sales of EVs to grow from just under 1% of total light vehicle sales in 2016 to around 20% of sales in 2025, rising to 50% of sales in 2030, the offsetting impact of global vehicle population growth creates the result that the global population of internal combustion engine (ICE) vehicles does not peak for another 10 years. After the peak of 1.5bn in 2028, the population of ICE vehicles moves into relatively shallow decline, returning to the number of ICE vehicles that we see in the world today (1.2bn) in around 2036.

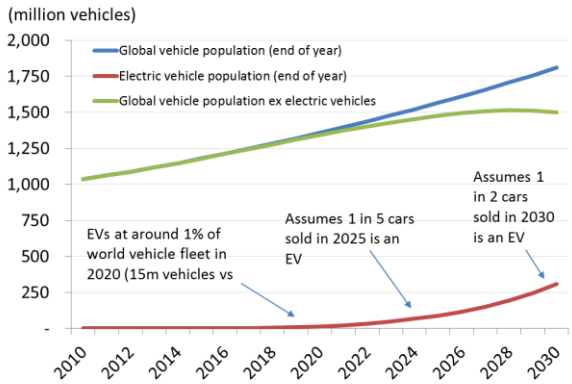
World light vehicle population (1960-2030e)



Source: Bloomberg, Guinness Atkinson

Forecasts are inherently limited and cannot be relied upon. Holdings are subject to change.

World light vehicle population: growth of EVs vs non-EVs (2010-2030e)



Source: IHS, Guinness Atkinson

Forecasts are inherently limited and cannot be relied upon. Holdings are subject to change.

As EV adoption progresses over the next 10 or 15 years, we must acknowledge that the fuel efficiency of the ICE portion of the market will improve, which will put further pressure on oil demand growth from the fleet. Taken together, we believe a growing fleet, improving fuel efficiency and EV penetration all point to oil demand from cars and light vehicles peaking in the mid to late 2020s.

Structure of global oil demand

Source of demand	%
Power	6%
Petrochemicals	13%
Other industry	11%
Cars & light trucks	26%
Heavy vehicles	18%
Air travel	6%
Shipping	6%
Rail	1%
Other	13%
Total	**100%**

Source: BP; Bernstein; Guinness Atkinson Funds

We must then consider oil demand from light vehicles in the context of total oil consumption. Light vehicles account for around 26% of global oil usage, with other sources of transportation (heavy vehicles, air, shipping and rail) accounting for around 31% of demand, and petrochemicals, other industry and power account making up most of the rest. Electrification of heavier road vehicles will come eventually, but is some way behind, mainly due to range issues.

Assessing the direction of oil demand growth over the next decade or two also, therefore, requires consideration of how other uses of oil are likely to evolve. Between 2015 and 2030, real GDP is expected to grow by 75% from $69trn to around $120trn (World Bank). Behind this, there will be a very significant increase in the number of trucks, air passenger miles, ethylene production and seaborne trade.

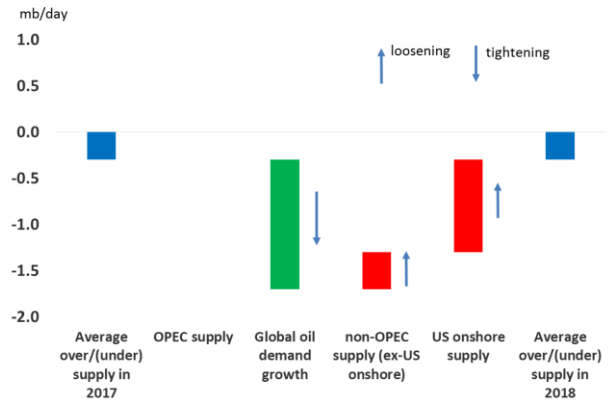
In isolation, these impacts would put enormous upward pressure on oil demand, implying average growth of around 2m b/day each year between now and 2030. However, once we factor in improving efficiency of the light vehicle fleet, efficiencies for other types of vehicle and in other industries, plus the penetration of EVs, the net effect is persistent but slowing demand growth into 2030. And when will oil demand then peak? The most likely scenario would be sometime around the mid 2030s, reaching a peak of around 115m b/day about 15-20 years from now. This would imply average demand growth of 1m b/day between now and the peak; higher than that in the near years and tailing off in later years. The signs still therefore point to significant new oil resources being required to keep up with continuing demand growth.

Oil inventories and conclusions

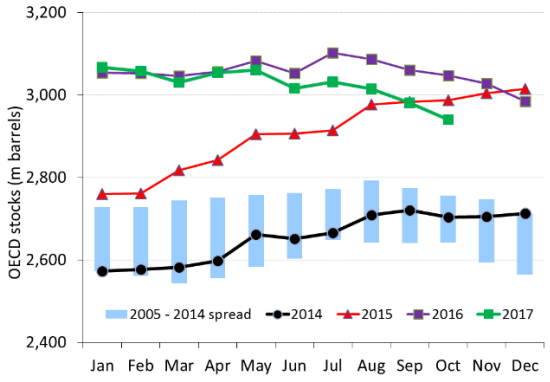
As ever, the picture of oil supply and demand in 2018 will be dynamic, depending on price, corporate behavior and macro-economic factors. However, we conclude that it is still useful to present a 'base' case, or starting-point for the oil demand/supply balance, as we see it today.

If we pull together our supply and demand expectations for 2018, it shows that the oil market is likely to be similar to 2017: undersupplied by something between zero and 0.5m b/day. This is based on the assumption that OPEC production will be flat on average and that global oil demand growth will be offset by a rise in US onshore production and other non-OPEC countries.

2018 global oil market balance



OECD oil and oil product inventories



Source: Guinness Atkinson Asset Management
Forecasts are inherently limited and cannot be relied upon.

Reconciling our base case view on supply and demand with the current state of OECD inventories, we expect inventories to continue in shallow decline in 2018, returning towards the 10-year seasonal norms. Historically, a decline in inventories has coincided with a strengthening oil price. The state of inventories in the middle of the year, together with oil prices will be key factors for Saudi and other participating producers in deciding whether to continue with the adopted quota cuts, or start to taper them.

OPEC are striving to find a 'happy medium' for the oil market where their own economics are better satisfied, the world economy is kept stable and US oil production grows in a controlled manner. Absent a supply shock, we believe that the oil price that achieves this is around in 2018 is around $55-60/bl. Looking further ahead, we believe that continued oil demand growth, and a decline in non-OPEC supply outside the US, will raise the call on the US shale system and OPEC, and allow OPEC to manage the market to a higher price.

Natural gas markets

The US natural gas market was in under-supply for nearly all of 2017, though the market moved closer to balance by the end of the year. The key features were:

- Return to growth in associated (by-product) gas from shale oil production;
- Small pick-up in low-cost Marcellus and neighboring Utica fields in the north-east of the country;
- Muted demand growth. LNG exports from the US Gulf Coast rose by around 2 Bcf/day, but were more than offset by declining demand from power generation, as higher gas prices prompted gas to coal switching.

The outlook for natural gas in the US in 2018 is likely to be defined by various factors:

- A significant rise in onshore production, as around 1m b/day of shale oil growth brings with it around 3 Bcf/day of associated gas production;
- Continued shallow growth of supply in the Marcellus/Utica fields, though only if local price differentials stay close enough to 'national' Henry Hub pricing;
- A better year for demand growth; LNG export growth will only be small (a number of 2018 start-ups have been pushed into 2019), but assuming normal weather, residential heating demand, power generation and industrial are all expected to increase moderately.

US natural gas supply/demand model (2007 – 2018)

Bcf/day	2007	2008	*2009*	2010	2011	2012	2013	2014	2015	2016	2017E	2018E
US natural gas demand:												
Residential/commercial	21.2	22.0	21.6	21.6	21.6	19.2	22.4	23.4	21.4	20.5	20.9	21.7
Power generation	18.7	18.2	18.8	20.2	20.8	24.9	22.3	22.3	26.5	27.3	24.6	25.8
Industrial	18.2	18.2	16.9	18.5	19.0	19.7	20.3	20.9	20.6	21.1	21.4	21.6
Pipeline exports (Canada & Mexico)	2.1	2.5	2.8	2.9	4.1	4.4	4.4	4.1	4.9	6.3	6.7	7.3
LNG exports	-	-	-	-	-	-	-	-	0.1	1.0	3.1	3.4
Pipeline/plant/other	5.2	5.3	5.5	5.6	5.8	6.1	6.7	6.3	6.5	6.4	6.4	6.4
Total demand	**65.4**	**66.2**	**65.6**	**68.8**	**71.3**	**74.3**	**76.1**	**77.0**	**80.0**	**82.6**	**83.1**	**86.2**
Demand growth	4.0	0.8	- 0.6	3.2	2.5	3.0	1.8	0.9	3.0	2.6	0.5	3.1

Bcf/day	2007	2008	*2009*	2010	2011	2012	2013	2014	2015	2016	2017E	2018E
US natural gas supply:												
US onshore	45.1	48.8	49.8	52.2	57.7	61.5	63.1	67.5	70.5	68.9	69.9	75.4
US offshore (Gulf of Mexico)	7.7	6.3	6.7	6.2	5.0	4.2	3.6	3.4	3.6	3.4	3.2	3.2
Pipeline imports (Canada)	10.4	9.8	9.0	9.0	8.5	8.0	7.5	7.1	7.1	8.0	7.9	7.4
LNG imports & other	2.3	1.2	1.4	1.4	1.0	0.8	0.6	0.5	0.5	0.4	0.3	0.4
Total supply	**65.5**	**66.1**	**66.9**	**68.8**	**72.2**	**74.5**	**74.8**	**78.5**	**81.7**	**80.7**	**81.3**	**86.4**
Supply growth	3.2	0.6	0.8	1.9	3.4	2.3	0.3	3.7	3.2	- 1.0	0.6	5.1
(Supply)/demand balance	- 0.1	0.1	- 1.3	-	- 0.9	- 0.2	1.3	- 1.5	- 1.7	1.9	1.8	- 0.2

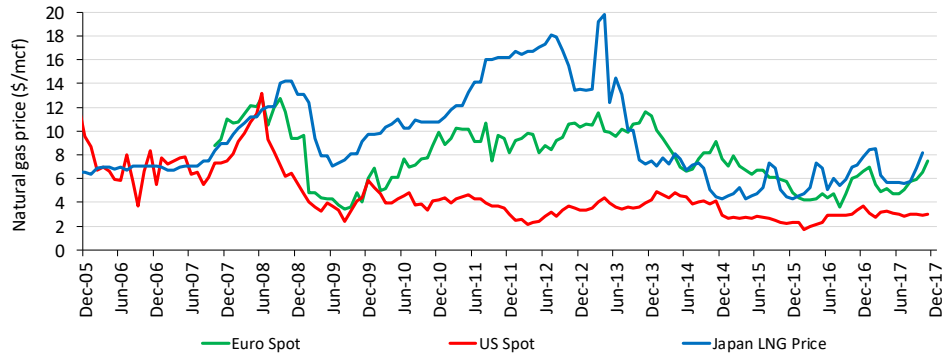
Source: EIA; Simmons, Guinness Atkinson

Forecasts are inherently limited and cannot be relied upon. Holdings are subject to change.

The US natural gas price since 2010 has fluctuated in a band between around $2 and $4/mcf. The extremes of this range have tended to coincide with warm and cold winters, and any sustained recovery over $3/mcf has generally been muted by strength in gas supply, particularly from the Marcellus/Utica and from gas produced as a by-product of shale oil. We expect prices to be held, for now, in the $2.75-3.25/mcf range, but will keep an eye on new sources of demand as the catalyst for prices to settle at the top end of this range. In particular, there is a wave of new LNG export facilities scheduled to arrive in 2019.

International gas prices (Europe and Asia) were soft in the first half of 2017, pulled lower by a warm Northern hemisphere winter, but rallied later in the year thanks to a tightening Asian LNG market. By the end of 2017, they had recovered to the top of the $6-8/mcf trading range. We expect this range to persist in 2018.

International natural gas prices 2005-17



Source: Bloomberg; Guinness Atkinson

Energy equities

After a year of recovery for energy equities in 2016, the strength of other equity sectors in 2017 saw energy underperform (MSCI World up 23.07% versus MSCI Energy up 5.95%). This leaves the relative valuation of energy equities at particularly depressed levels compared to history.

On a relative price-to-book (P/B) basis (versus the S&P500), the valuation of energy equities has fallen back to a 50 year low, at 0.5x, the same level that they were at in February 2016 when Brent oil was $29/bl. We see the low P/B ratio for the energy sector as driven by poor levels of return on capital employed (historically the two measures are closely correlated). However, we saw clear signs of improvement in return metrics in 2017, particularly in improving free cash flow returns, which tend to lead ROCE at the start of an upcycle.

Here, we explore the current energy equity valuations in more detail, assess what the re-rating potential of the sector could plausibly be, and explain how these views shape our current portfolio.

Capital discipline and improving free cash flow generation

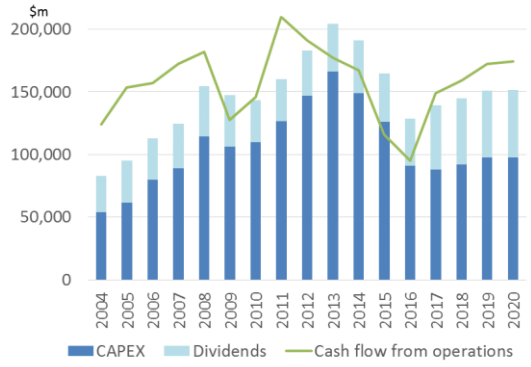
In 2017, we saw clearer signs that many energy companies have adapted successfully to the lower oil price environment. We appear to have entered a world of capital discipline for the energy sector and the buzz words for 2018 are now *'lower capital expenditure', 'lower operating costs', 'stronger free cash flow generation', 'living within cash flows', 'focus on profitability'* and *'greater distributions to shareholders'*.

For the super majors (BP, Shell, TOTAL, Exxon and Chevron) and other large cap oil & gas companies, capital indiscipline reached an extreme in 2013 and 2014, such that they were unable to cover dividends from free cash flow, even though oil was at $100/bl. By 2016, in response to lower oil prices and falling revenues, cost cutting was underway, but the concept of energy companies covering their dividends at $55/bl Brent remained a significant stretch. In 2017, however, covering the dividend at $55/bl oil became a reality, with most companies removing their scrip dividends (or their discounts to their scrip dividends) and some recently introducing share buyback programs. This has been broadcast most widely for the super majors but is arguably not reflected in their dividend yields yet. And looking towards the end of the

decade, in a $60/bl Brent oil price environment, we see room for distributions to shareholders from the super majors to rise by around 40%. This is quite a thought and, we believe, far from the market view. In practice, we expect ordinary dividends not to increase (because they cannot be cut again), but the returns to shareholders to come in the form of enhanced share buybacks and a reduction of debt.

The inflection in free cash flow for the super majors is impressive, but we see an even greater improvement occurring for the next tier of companies: mid-cap integrateds; large cap E&Ps and Canadian oil sands majors. These companies too have restructured dramatically and have covered dividends and capital expenditure commitments in 2017 at a $55/bl oil price. However, projecting forward with a $60/bl oil price in 2019 and 2020, we see room for an 80% increase in shareholder distributions (versus 40% for the super majors). There are now a number of large cap companies within the energy sector that offer the potential for dividend growth at $60/bl Brent, and this is an important focus in the Guinness Atkinson portfolio.

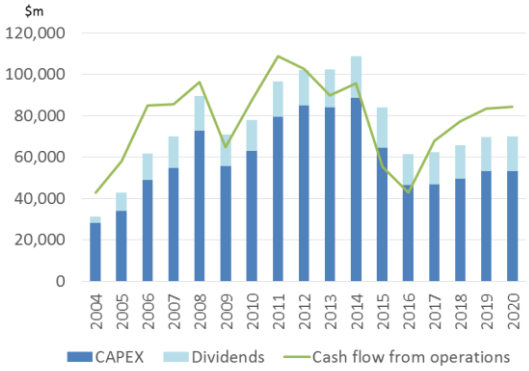
Super majors – free cash flow generation



Source: Bloomberg; Guinness Atkinson

Forecasts are inherently limited and cannot be relied upon.

Other large caps – free cash flow generation

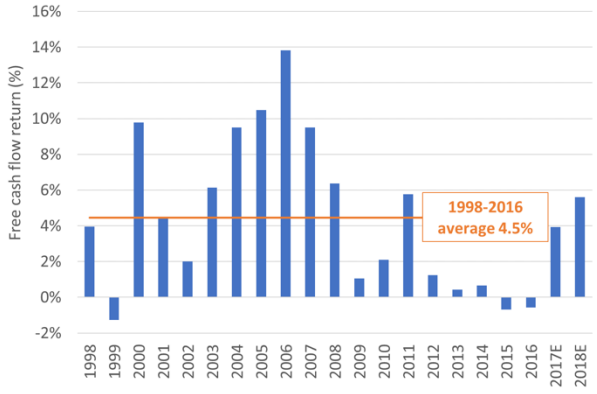


Source: Bloomberg; Guinness Atkinson

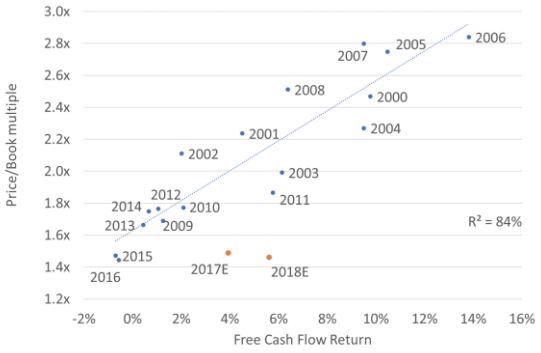
Forecasts are inherently limited and cannot be relied upon.

For the Guinness Atkinson Energy portfolio as a whole, we see the potential for a significant increase in free cash flow (FCF) return (defined as post-tax operating cash after capex, divided by capital employed). After five years (2012-2016) of delivering zero FCF return, we have witnessed a sharp increase in this measure, reaching just under 4% in 2017. This is slightly below the long run average over the last twenty years (4.5%) for the same group of companies. Our 2018 estimate for FCF return (based on $55/bl Brent) at nearly 6% exceeds the long run average and should be positive for the valuation of energy equities.

FCF history - Guinness Atkinson fund



FCF vs P/B ratio – Guinness Atkinson fund

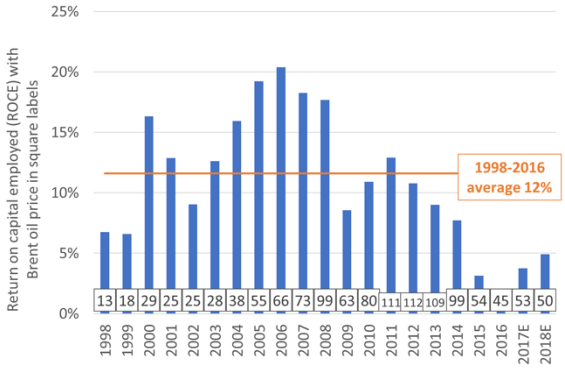


Source: Bloomberg, Company Data and includes analysis of all 'full position' holdings (for which 1998-2017 data is available) in the Guinness Atkinson Global Energy fund as of December 31, 2017. FCF = free cash flow return. Past performance is no guarantee of future results. Holdings are subject to change. Forecasts are inherently limited and cannot be relied upon.

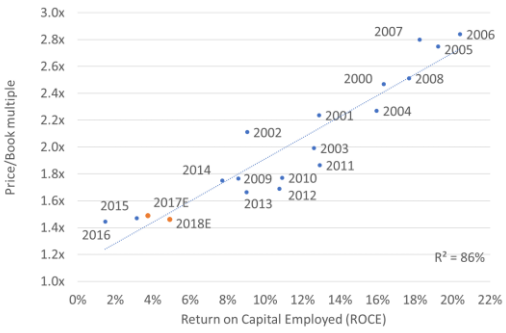
Measured by the long-term relationship between FCF return and price to book multiple (see the scatter chart above), we can see that the market is not yet willing to 'pay' for this free cash flow generation. The current P/B multiple for the portfolio of 1.5x implies that the companies will deliver zero free cash flow into perpetuity. However, based on the long-term correlation, we would expect to see a 6% FCF return for the portfolio translate into a P/B multiple re-rating of 2-2.2x (i.e. upside of 35-45%). We presume that the market would like to see the FCF being sustained before choosing to pay up for it. The companies will need to demonstrate over time that lower capex spending can be sustained and that their dividends will remain fully covered. We are cautiously optimistic on their ability to do this (given the dramatic cost reductions in the industry) and expect to see capex increase by only around 10% from the current levels over the next 2-3 years.

We see a similar trend when considering return on capital employed (ROCE) for the same companies. There are signs that ROCE is starting to improve; we expect ROCE of 5% in 2018 based on a $55/bl Brent oil price environment versus the actual ROCE of 3% delivered in 2015 at a $54/bl Brent oil price. However, the ROCE metric is slow moving (the delay stems predominantly from depreciation rates taking time to work through the P&L) and the market appears only willing to 'pay' for a sustainable level of ROCE of around 4-5%. We note that this is significantly lower than the long run average ROCE for the companies and implies that the market is expecting energy sector profitability to remain below the cost of capital. We disagree and expect ROCE to normalize to the long run average of 10-12%, but that recovery will take a few more years. Few companies currently have ROCE targets but we would expect to see a greater focus on them (or other profitability metrics rather than growth metrics) this year.

ROCE history - Guinness Atkinson fund



ROCE vs P/B ratio –Guinness Atkinson fund



Source: Bloomberg, Company Data and includes analysis of all 'full position' holdings (for which 1998-2017 data is available) in the Guinness Atkinson Global Energy fund as of December 31, 2017. ROCE=return on capital employed. Past performance is no guarantee of future results. Holdings are subject to change. Forecasts are inherently limited and cannot be relied upon.

So, whilst we expect a supportive oil price environment, the underlying profitability and free cash flow generation of our portfolio will depend as much on improving capital discipline, lower unit capex and operating costs, and a continued rationalization of balance sheets. We are encouraged by the steps that many investee companies took in 2017, and look forward to further improvements in 2018.

In our portfolio, we currently combine the themes of expanding free cash flow for mid to large caps, higher ROCE for the super majors, and North American shale oil & gas growth as key areas of exposure:

Key themes in the Guinness Atkinson energy portfolio

	Theme	Example holdings	Weighting (%)
1	Expanding free cashflow yields from large-cap oil & gas		29.2%
2	North American shale oil & gas growth		27.4%
3	Growing return on capital from oil & gas majors		17.7%
4	Emerging market natural gas demand growth		10.8%
5	Strong refining margins resulting from global GDP growth		7.2%
6	Deleveraging balance sheets		2.7%
7	Growth in global solar market		1.4%
8	Other (incl cash)		3.5%

Source: Source: Guinness Atkinson Asset Management, at end of Dec. 2017. Fund holdings & sector allocations are subject to change and are not recommendations to buy or sell any security.

Top 10 holdings as of December 31, 2017 were 1. Suncor Energy Inc (3.66%), 2. ConocoPhillips (3.63%), 3. Halliburton Co (3.63%), 4. PetroChina Co Ltd (3.62%), 5. Devon Energy Corp (3.62%), 6. Royal Dutch Shell PLC (3.60%), 7. Schlumberger (3.60%), 8. OMV AG (3.58%), 9. CNOOC Ltd (3.57%) and 10. Occidental Petroleum Corp (3.56%)

Will Riley, Jonathan Waghorn & Tim Guinness
January 2018

Opinions expressed are those of Guinness Atkinson Funds, are subject to change, are not guaranteed and should not be considered investment advice.

The Fund's investment objectives, risks, charges and expenses must be considered carefully before investing. The statutory and summary prospectus contains this and other important information about the investment company, and it may be obtained by calling 800-915-6566 or visiting gafunds.com. Read it carefully before investing.

The Fund's holdings, industry sector weightings and geographic weightings may change at any time due to ongoing portfolio management. References to specific investments and weightings should not be construed as a recommendation by the Fund or Guinness Atkinson Asset Management, Inc. to buy or sell the securities. Current and future portfolio holdings are subject to risk.

Mutual fund investing involves risk and loss of principal is possible. The Fund invests in foreign securities which will involve greater volatility, political, economic and currency risks and differences in accounting methods. The Fund is non-diversified meaning it concentrates its assets in fewer individual holdings than a diversified fund. Therefore, the Fund is more exposed to individual stock volatility than a diversified fund. The Fund also invests in smaller companies, which involve additional risks such as limited liquidity and greater volatility. The Fund's focus on the energy sector to the exclusion of other sectors exposes the Fund to greater market risk and potential monetary losses than if the Fund's assets were diversified among various sectors. The decline in the prices of energy (oil, gas, electricity) or alternative energy supplies would likely have a negative effect on the fund's holdings.

S&P 500 Index is a broad based unmanaged index of 500 stocks, which is widely recognized as representative of the equity market in general.

MSCI World Energy Index is a free-float weighted equity index based on the energy sector.

MSCI World Index is a capitalization weighted index that monitors the performance of stocks from around the world.

One cannot invest directly in and index.

Price to Book Ratio (P/B) is used to compare a stock's market value to its book value and is calculated by dividing the current closing price of the stock by the latest quarter's book value per share.

Standard Deviation (SD) is applied to the annual rate of return of an investment to measure the investment's volatility. Standard deviation is also known as historical volatility and is used by investors as a gauge for the amount of expected volatility.

Return on Capital (ROCE) is a return from an investment that is not considered income. The return of capital is when some or all of the money an investor has in an investment is paid back to him or her, thus decreasing the value of the investment.

Contango is a situation where the futures price of a commodity is above the expected future spot price.

Backwardation is the market condition where the price of a commodities' forward or futures contract is trading below the expected spot price at contract maturity.

The Compound Annual Growth Rate (CAGR) is the mean annual growth rate of an investment over a specified period of time longer than one year.

OPEC-12 are the 12 countries that make up OPEC (Organization of Petroleum Exporting Countries): Venezuela, Saudi Arabia, Iran, Iraq, Kuwait, United Arab Emirates (UAE), Libya, Nigeria, Qatar, Algeria, Angola, Ecuador

Bid-Ask Spread is the amount by which the ask price exceeds the bid.

CAPEX or Capital Expenditure are funds used by a company to acquire or upgrade physical assets such as property, industrial buildings or equipment.

Click here for a complete list of holdings of the Guinness Atkinson Global Energy Fund.

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Holdings are subject to change.
Distributed by Foreside Fund Services, LLC.